COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

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In the Matter of:

GENERAL ADJUSTMENT IN ELECTRIC RATES OF KENTUCKY POWER COMPANY	))	CASE NO. 9061

O R D E R

On June 15, 1984, Kentucky Power Company ("Kentucky Power") filed its application with the Commission requesting authority to increase its rates for service rendered on and after July 5, 1984. The proposed rates would increase Kentucky Power's annual revenues by $51.7 million, an increase of 26.6 percent over normalized revenues.

The Commission suspended the proposed rate increase until December 5, 1984, in order to conduct public hearings and investigations into the reasonableness of the proposed rates. A hearing was scheduled for October 9, 1984, for the purpose of cross-examination of the witnesses of Kentucky Power and the intervenors. Kentucky Power was directed to give notice to its consumers of the proposed rates and the scheduled hearing pursuant to 807 KAR 5:025, Section 7. Motions to intervene in this matter were filed by the Consumer Protection Division in the Office of the Attorney General ("AG"), the Kentucky Industrial Utility Customers ("KIUC"), the Office of Kentucky Legal Services Programs on behalf of several residential customers and the Concerned

Citizens of Martin County ("Residential Intervenors"), and Blue Diamond Coal Company. These motions were granted and no other parties formally intervened.

The hearing for the purpose of cross-examination of the witnesses of Kentucky Power and the intervenors was held in the Commission's offices in Frankfort, Kentucky, on October 9-12, 1984, with all parties of record represented. Briefs were filed by November 5, 1984, and responses to all data requests have been filed. The records of the following Commission cases were incorporated by reference and made a part of the record in this case:

1. Case No. 8271, The Application of Kentucky Power Company for a Certificate of Public Convenience and Necessity.

2. Case No. 8904, An Investigation of the Necessity and Usefulness of and the Cost Responsibility for the Hanging Rock-Jefferson 765 KV Transmission Line Under Construction by Kentucky Power.

3. Case No. 8734, General Adjustment in Electric Rates of Kentucky Power Company.

In addition, the records of the following cases before the Federal Energy Regulatory Commission ("FERC") were incorporated by reference and made a part of the record in this case:

4. FERC Docket No. ER84-348-001, American Electric Power Service Corporation.

5. FERC Docket No. ER84-579-000, American Electric Power Generating Company.

COMMENTARY

Kentucky Power is a wholly-owned subsidiary of the American Electric Power Company ("AEP") and serves approximately 145,000 customers in 20 eastern Kentucky counties. In addition to its retail customers, Kentucky Power serves two municipal power systems. Most of Kentucky Power's corporate officers are also officers of AEP or other AEP subsidiaries.

This Order addresses the Commission's findings and determinations on issues presented and disclosed in the hearing and investigation of Kentucky Power's revenue requirements and rate design. Kentucky Power requested additional revenue of approximately $51.7 million and this Order authorizes rates and charges that will produce additional revenues of approximately $29.6 million. The revenue requested in this case included approximately $30 million in expense resulting from the cost to Kentucky Power for a unit power agreement under which it would purchase 15 percent of the capacity of the Rockport Generating Plant ("Rockport"). The request also included approximately $6 million in additional revenue for the return and operating expenses associated with the Hanging Rock-Jefferson transmission line ("Hanging Rock-Jefferson"). The modification of these requests along with the lower rate of return granted herein are the primary reasons that the increase granted is significantly less than the amount requested.

TEST PERIOD

Kentucky Power proposed and the Commission has accepted the 12-month period ending March 31, 1984, as the test period for determining the reasonableness of the proposed rates. In utilizing the historic test period, the Commission has given full consideration to appropriate known and measurable changes.

ROCKPORT - UNIT POWER AGREEMENT

At the time this rate case was filed, Case No. 8271, Kentucky Power's application to purchase a 15 percent ownership interest in the Rockport generating plant, was pending before this Commission. Accordingly, this rate application originally requested recovery of the costs associated with that ownership. On August 2, 1984, the Commission issued its Order in that case wherein it denied Kentucky Power's request and directed Kentucky Power to continue to purchase power from the AEP pool. Subsequent to the Commission's ruling in Case No. 8271, Kentucky Power revised its application herein to request recovery of the costs associated with purchase of unit power from the American Electric Power Generating Company ("AEG"), a sister corporation of Kentucky Power. The unit power agreement would obligate Kentucky Power for 15 years (plus a 5-year renewal option) to pay 15 percent of all costs associated with the Rockport generating plant consisting of two 1300 MW units, in return for the right to receive 15 percent of the power generated therefrom.

Kentucky Power's request to recover the annual capacity costs of $37.1 million associated with the Rockport unit power agreement is one of the major issues in this case. Since Kentucky Power and AEG are both wholly-owned subsidiaries of AEP, they are not dealing at arms length. Consequently, this transaction must be closely scrutinized to insure that the public interest is protected.

The AG, KIUC and the Residential Intervenors all argued that the proposed unit power agreement was in direct contravention of the Commission's decision in Case No. 8271 as the agreement is merely a different means of gaining access to the capacity of the Rockport plant. The Residential Intervenors argued that Kentucky Power has chosen to ignore the Commission's findings and decision in Case No. 8271 in spite of the fact that the decision was not appealed. All the intervenors maintained that the doctrine of res judicata was applicable and that Kentucky Power had failed to prove the existence of changed circumstances to support a modification of the Order in Case No. 8271.

Kentucky Power argued that res judicata has no application in rate-making proceedings because they are legislative in nature and, in the alternative, that res judicata should not be applied since the issue of Rockport unit power is not identical to the adjudication in Case No. 8271 regarding Rockport ownership. Contrary to Kentucky Power's argument, Mr. Robert Matthews, President of Kentucky Power, testified that:

> . . .the unit power agreement between AEG and Kentucky Power provides that AEG shall make available to Kentucky Power 30% of the power and associated energy available to AEG at the Rockport plant, and Kentucky Power will pay the amounts which I&M would have paid for that 30% share. Kentucky Power's 30% share of AEG's 50% entitlement is, of course, equivalent to the 15% of Rockport which Kentucky Power would have been entitled to under direct ownership, as originally sought.[1]

1 Matthews Supplemental Testimony, page 8.

The Commission recognizes that the Supreme Court of Kentucky has ruled that ". . .res judicata has some application to administrative proceedings under certain circumstances. That is not so where significant change of conditions or circumstances occur between two successive administrative hearings."[2] The Commission is of the opinion that the purchase of Rockport unit power is essentially the same as the outright purchase of an ownership interest in Rockport since under either scenario Kentucky Power would be financially responsible for 15 percent of all Rockport costs and entitled to receive 15 percent of the power.

The Commission further finds that although this proceeding is characterized as a rate case, it is impossible to determine whether the cost of the 20-year unit power agreement (15-year initial term plus 5-year renewal option) should be allowed as a rate-making expense until the agreement is adjudged to be necessary and prudent. Consequently, the Commission's Order in Case No. 8271 should only be modified if the evidence indicates a significant change of conditions or circumstances.

The starting point for the Commission's decision must be a review of the August 2, 1984, Order in Case No. 8271. That Order was premised on five basic findings of fact. First, the Commission found that Kentucky Power needed capacity. Second, Kentucky Power under the terms of the AEP Interconnection Agreement has the

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2 Bank of Shelbyville v. Peoples Bank of Bagdad, Ky., 551 S.W.2d 234, 236 (1977).

right to purchase capacity from the AEP pool. Third, AEP has excess capacity. Fourth, purchasing capacity under the terms of the AEP Interconnection Agreement is cheaper than purchasing a 15 percent interest in Rockport and therefore Kentucky Power should invoke its rights to purchase capacity from the AEP pool. Fifth, Kentucky Power's membership in the AEP pool would not be jeopardized if it continued to purchase capacity under the capacity agreement.

Because of the impending December 1, 1984, commercial date of operation of the Rockport 1 unit, Kentucky Power chose to neither request a rehearing of the Commission's decision in Case No. 8271 nor to appeal the Commission's decision in court. Instead, Kentucky Power chose to execute a unit power agreement to purchase 15 percent of the output of Rockport. The unit power contract was signed by Mr. Matthews on August 1, 1984. On August 2, 1984, the unit power contract was filed with the FERC for its approval. The FERC has established Docket No. ER 84-579-000 to consider the reasonableness of the rates set forth in the unit power contract. This Commission has intervened in the FERC case.

Although Kentucky Power did not challenge the Commission's findings in Case No. 8271 in a rehearing request or a court appeal, it has challenged several of those findings in this case. Kentucky Power has not challenged the Commission's findings that it needs power, but it has disagreed with the Commission's finding that Kentucky Power has the right under the Interconnection Agreement to meet its need for power by purchasing capacity from the AEP pool. In this case Kentucky Power reiterated the arguments it presented in Case No. 8271 that to continue to purchase under the Interconnection Agreement is unfair to the other parties to the Agreement and further that Kentucky Power has an obligation to provide capacity to the pool. Mr. Matthews stated that if Kentucky Power was able to:

> continue with the purchase of power from the pool, we would really be shifting a responsibility for capacity which we need more than any other member to members of another jurisdiction. That's not fair, and it really would be destructive of the pooling concept.[3]

However, the Interconnection Agreement contains no obligation for a member to maintain any specific level of capacity. Mr. Matthews expressed this point in his supplemental testimony where he stated that, "[s]uch an obligation [to provide capacity to meet one's own needs] is implicit in the Interconnection Agreement."[4]

These same arguments were put forth by Kentucky Power on this issue in Case No. 8271 and considered by the Commission in that case. However, the Commission has undertaken a renewed review of the Interconnection Agreement to determine if such an obligation should be applied in this case. The Interconnection Agreement contains no standards or guidelines to indicate how much generating capacity each member should possess, the circumstances under which a member must add capacity or the timing of capacity additions. The Interconnection Agreement explicitly requires each

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3 Transcript of Evidence ("T.E."), Volume I, October 9, 1984, page 24.

4 Matthews Supplemental Testimony, page 4.

member to make its capacity available to the pool and imposes monthly charges upon those members who have a capacity deficit. These charges are paid to those members who have a capacity surplus. This evidence can only support a finding that a member has the option of either adding additional capacity when needed or purchasing such capacity from the pool and paying the requisite monthly charges. The Interconnection Agreement further provides that in this case when new generating capacity such as the Rockport plant is added to the AEP system, the monthly capacity charges to be paid by Kentucky Power will increase.

Kentucky Power has advanced one new argument on this issue in its brief. That argument is that since the parties to the Interconnection Agreement interpret the Agreement as imposing on Kentucky Power an obligation to add new generation capacity, the Commission must accept the parties' interpretation. Although the brief cites Dennis v. Watson, Ky., 264 S.W.2d 858 (1953); Rudd-Melikian, Inc. v. Merritt, 282 F.2d 924 (6th Cir. 1960) and Wilcox v. Wilcox, Ky., 406 S.W.2d 152 (1966) for support, those cases are clearly distinguishable. The cited cases involved controversies between contracting parties acting at arms length, not affiliated entities. Further, the courts gave deference only to the parties' interpretation of their contract prior to the controversy under review. Here Kentucky Power has presented no evidence of the members' interpretation of the Interconnection Agreement prior to this controversy. Kentucky Power has merely presented the members' interpretation of this controversy. The Commission is clearly not bound by this self-serving evidence.

Kentucky Power has also challenged the Commission's finding in Case No. 8271 that AEP has excess capacity. During cross-examination of Mr. Gregory S. Vassell, Senior Vice President - System Planning and a Director of the AEP Service Corporation, the AEP reserve margin for the winter 1983-84 was determined to be 43.9 percent based on the AEP internal demand.[5] However this figure did not include the Rockport unit. The projected reserve margin for the winter 1984-85, which includes Rockport unit 1, was calculated to be 50.7 percent.[6] Most electric systems are planned around a 20 - 25 percent reserve margin in order to maintain reliable electric service. Some might even argue that an integrated system such as the AEP system could maintain even lower reserve margins. Nevertheless, the 40 and 50 percent reserve margins identified above certainly appear excessive. However, Mr. Vassell contended that because of AEP's sales to other companies and because of the economies of scale available to AEP the economic burden of the reserves on the AEP ratepayers is reduced.[7] During a break in the hearing, Mr. Vassell prepared an exhibit, GSV-2, which recalculated the AEP reserve margins at 15.1 percent when the net revenues from AEP's sales to other companies were included. Although Mr. Vassell's recalculation of the reserve margin is a means to disguise 50 percent reserve margins, the fact remains that there is only one group that is responsible for

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5 T.E., Volume I, October 9, 1984, page 264.

6 T.E., Volume II, October 10, 1984, page 177.

7 T.E., Volume I, October 9, 1984, page 253.

paying for the carrying costs of the excess capacity if the system sales do not materialize. That group is the ratepayers. Clearly there is a risk of these system sales declining. This risk is easily depicted with reference to Kentucky Power's response to request 5 of the Commission's Order of October 25, 1984. This response shows system sales in 1982 and 1983 declining by over 30 percent from the 1981 level. The sales in 1982 and 1983 were even below the level attained 3 years earlier in 1979. The Commission remains of the opinion that the reserves of the AEP system are excessive relative to most standard utility measures.

Kentucky Power in this case challenged the Commission's finding in Case No. 8271 that it would be cheaper to purchase capacity under the terms of the AEP Interconnection Agreement than to purchase 15 percent of Rockport directly. In order to rebut this finding, Kentucky Power filed on October 3, 1984, less than 1 week prior to the hearing, a study entitled the "Economic Value of Unit Power" sponsored by Mr. Joseph H. Vipperman, Vice President and Controller for the AEP Service Corporation. Normally, the Commission could not have accepted such a late-filed voluminous study; however, in this case the study was filed in response to the Commission's recently issued Order in Case No. 8271. Because of these extenuating circumstances, the Commission allowed the exhibit and workpapers to be filed with the condition that after all parties had sufficient time to review the documents, a further hearing would be scheduled if any party requested one. No further hearing was requested. The study purported to show that "the Kentucky Power ratepayer will enjoy an economic benefit as a result of the Unit Power Agreement."[8] The workpapers to support the study numbered over 680 pages. On October 17, 1984, Commission staff, intervenors and Kentucky Power met in an informal conference to review the study.

Mr. Vipperman's study attempted to quantify the value of the unit power agreement to Kentucky Power ratepayers. Because of the duration of the unit power agreement, it was necessary for Mr. Vipperman to evaluate the costs and benefits associated with the unit power agreement over a 20-year period. A net present value analysis was required to evaluate the cost comparisons of the unit power agreement versus purchases elsewhere during the 20-year period. In order to perform the net present value analysis, numerous assumptions were required. Assumptions were made concerning load forecasts for Kentucky Power and the other AEP subsidiaries, discount rates, inflation rate forecasts and required reserve margins. Also, assumptions about how and at what price capacity would be provided to the pool when the system's reserve margin dipped below the required levels. For his study, Mr. Vipperman assumed load growth in the range of 1.5 to 3.0 percent; discount rates in the range of 9 to 12 percent; inflation rates in the range of 6 to 8 percent; and required reserve margins of either 20 or 25 percent. Mr. Vipperman also assumed that capacity could be purchased by Kentucky Power under the terms of the Interconnection Agreement unless the system's reserve margin

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8 Response to Item 36, page 1 of Study, Commission First Data Request.

was less than the required level. When capacity is needed by the pool to raise the system's reserve margin to the required level, Mr. Vipperman assumed that the company with the lowest reserve margin must purchase capacity outside of the system until its reserves are equal to the reserves of the company with the next lowest margin. If the reserves of the AEP pool were still below the required level then both companies would purchase capacity outside of the system until their reserves were equal to the reserves of the company with the next lowest margin, and so on. When capacity was purchased outside of the AEP system, it was priced at the projected cost of East Kentucky Power Cooperative's J. K. Smith unit, escalated by a projected inflation rate. Currently, the J. K. Smith unit is projected to be completed in 1992 at a cost of $2,556 per kilowatt.

Mr. Vipperman's study evaluated various scenarios to determine if there are benefits to Kentucky Power's ratepayers from the unit power agreement. By using different assumed values in each scenario, Mr. Vipperman was able to calculate a net present value for each scenario. Therefore, his study provided a range of results. Generally, when the load growth on the AEP system was 2 percent or greater there was some positive benefit to the ratepayers. However, when the growth rate was assumed to be 1.5 percent, there was no net benefit to the ratepayers from the unit power agreement.

In any study of this magnitude, the Commission is very concerned about the preponderance of the assumptions. In this case this concern is heightened because of the short time provided to review the study and the implications of the assumptions. However, the Commission finds one assumption considerably more troubling than the others. That assumption is the use of the cost of J. K. Smith to determine the price of capacity purchased elsewhere. This is a troubling assumption because AEP often throughout this case and Case No. 8271 referred to its ability to take advantage of economies of scale by constructing larger generating units, the recent ones being 1300 MW. In fact, Mr. Vassell provided Exhibit GSV-3 during the second day of the hearings in this case to show that AEP can construct units at a per-kilowatt cost of approximately 62 percent[9] of the cost for a representative group of other companies. If Mr. Vipperman had assumed the construction of a generating unit by the AEP system during this 20-year period, then it is very likely that cheaper capacity would be available within the AEP pool. However, Mr. Vipperman's assumptions may have overestimated the cost of providing capacity to the AEP pool.

Another concern of the Commission is that the study originally filed by Mr. Vipperman does not take into account a recently completed unit power agreement with Virginia Electric Power Company ("VEPCO") to purchase 455 megawatts. However, by the time of the informal conference, some preliminary studies including the VEPCO unit power sale had been completed. It was clear that the

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9 GSV-3 provides an estimate of $855/KW for the cost of Rockport Unit 1. This is compared to a weighted average cost of five generating units built by non-affiliated companies of $1374/KW. The $855 estimate is 62 percent of $1374.

impact of the VEPCO sale was to considerably reduce the net benefits to the Kentucky Power ratepayers, and in certain scenarios the benefits were completely lost. For instance, utilizing Mr. Vipperman's assumption of 6 percent inflation, 2 percent load growth and a 20 percent required reserve margin, the following net present values for the scenario with the VEPCO sale and without the VEPCO sale are provided:

Discount Rate	Original Study No Sale to VEPCO ($000)	Revised Study With Sale to VEPCO ($000)
9 %	58,376	41,888
9.5%	44,201	28,255
10.0%	31,406	15,976
10.5%	19,861	4,926
11.0%	9,452	- 5,010
11.5%	74	-13,936
12.0%	- 8,369	-21,946

Clearly, this one sale has a tremendous impact on the results of the study.

Because the results in the late-filed Vipperman study vary so much with changes in assumptions and because there is so much uncertainty surrounding several of the assumptions, the Commission finds that it cannot accept this study as an affirmative demonstration that Kentucky Power and its ratepayers will receive a net economic benefit from the unit power agreement. Therefore, the Commission is of the opinion that it is less expensive for Kentucky Power to continue to purchase capacity under the Interconnection Agreement rather than to purchase Rockport power through a unit power agreement.

Kentucky Power has also challenged the Commission's finding in Case No. 8271 that Kentucky Power's membership in the AEP system would not be jeopardized if Kentucky Power continued to purchase capacity from the AEP pool. In the Order in Case No. 8271, the Commission recognized that the other parties to the AEP Interconnection Agreeement could seek to change the present allocation of costs and benefits. The record in this case clearly indicates that just as Kentucky Power needs the AEP system, so does the AEP system need Kentucky Power. Kentucky Power brings to the pool 1,066 megawatts of low cost baseload generating capacity, key transmission linkages and a strong and viable customer base. The AEP system is a fully integrated electrical system of which Kentucky Power is an integral part. Even though there could be a change in the present allocation of costs and benefits under the Interconnection Agreement, there is no credible evidence to support a finding that Kentucky Power's membership in the AEP system would be jeopardized it if continued to purchase capacity from the AEP pool.

The Commission has carefully considered Kentucky Power's arguments with respect to the jurisdictional limitations on this Commission due to the fact that the unit power agreement, being an interstate power transfer, is subject to the jurisdiction of the FERC. While the FERC has exclusive jurisdiction to determine a just and reasonable rate for an interstate power sale, this Commission has exclusive jurisdiction to determine Kentucky Power's retail cost of service for setting retail rates. By Order issued November 23, 1984, in Docket No. ER84-579-001, the FERC stated that the only issue to be adjudicated in the Rockport unit power case was the justness and reasonableness of the proposed rates and that there was no intent to make or consider any findings concerning Kentucky Power's prudence in entering the agreement, in light of the availability of alternative power supplies. The FERC further stated that:

> . . .a determination that the purchaser has purchased wisely or has made the best deal available. . .are legitimate concerns of the state Commissions and this Commission as well in determining whether purchases reflect prudently incurred expenses for purposes of determining the purchaser's rates for sales to others. [Pacific Power and Light Company, 27 FERC §61,080 (1984.)][10]

This Commission has made no findings on the justness or reasonableness of the rate set forth in the Rockport unit power agreement nor has any attempt been made to examine the cost of service supporting that rate. The Commission has, within the bounds of its jurisdiction, examined the availability of alternative power supplies to meet Kentucky Power's needs. Based on the evidence in this record, the Commission finds that Kentucky Power can acquire power sufficient to meet its needs by either purchasing Rockport unit power or continuing to purchase power from the AEP pool. The Commission further finds that to continue purchasing power from the AEP pool will be less costly to Kentucky Power and its ratepayers than the purchase of Rockport unit power. Consequently, for rate-making purposes the Commission finds that

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10 FERC Docket No. ER84-579-001, Order issued November 23, 1984, page 3.

Kentucky Power's decision to purchase Rockport unit power is unwise and imprudent since it is more costly than alternative power supplies. Kentucky Power can recover through its retail rates its actual cost of purchased power not to exceed the cost which would be incurred if power is purchased from the AEP pool rather than Rockport unit power.

HANGING ROCK-JEFFERSON TRANSMISSION LINE

In its original application, Kentucky Power proposed to recover the capital costs associated with the Hanging Rock-Jefferson line through a deferred recovery mechanism that would phase in those costs on a ratable basis over the next 5 years. Kentucky Power also proposed a 5-year phase-in of the transmission equalization receipts it expects to realize under the transmission agreement filed with the FERC under docket number ER84-348-001. On August 3, 1984, the Commission issued its Order in Case No. 8904 wherein it limited, for rate-making purposes, Kentucky Power's investment in the Hanging Rock-Jefferson line to the amount required to make Kentucky Power's investment in bulk transmission facilities equal to its member load ratio ("MLR") times the AEP system's investment in bulk transmission facilities. The Commission found that all investment in excess of this amount should not be recovered from Kentucky ratepayers as it would not be used and useful in Kentucky operations, and the Commission found that the portion of Kentucky Power's investment in the Hanging Rock-Jefferson line to be included in rate base should be phased in over 5 years.

Kentucky Power subsequently petitioned for a rehearing in Case No. 8904, which petition was denied in the Commission's Order of September 11, 1984. The matter is currently on appeal before the Franklin Circuit Court.

Subsequent to the Commission's Order in Case No. 8904, Kentucky Power filed supplemental testimony and exhibits in this proceeding wherein it attempted to show the negative financial impact of the Commission's decision therein and it continued to argue the merits of that decision. The AG and the Residential Intervenors maintained that the Commission's decision in Case No. 8904 was not an issue in this case except for the mechanics of the proposed phase-in and the deferred return.

In this proceeding, Kentucky Power stated that its 5-year phase-in was proposed to ameliorate the rate impact of the line's $123 million capital costs. Kentucky Power further stated that if the Commission limited the investment in the Hanging Rock-Jefferson line as set out in its Order in Case No. 8904, such limitation, to an amount of approximately $54 million, would obviate the need for any phase-in.

The Commission has not been persuaded by Kentucky Power's arguments regarding its decision in Case No. 8904 to limit Kentucky Power's investment in the Hanging Rock-Jefferson line. As that Order clearly stated, all investment above the amount needed to make Kentucky Power's investment in bulk transmission facilities equal to its MLR times the AEP system's investment in bulk transmission facilities is excess for Kentucky Power that will not be used and useful for Kentucky operations. The

Commission, therefore, affirms its decision in Case No. 8904 to limit, for rate-making purposes, Kentucky Power's investment in the Hanging Rock-Jefferson line to the amount that will be used and useful in Kentucky operations.

The Commission has determined that, with the above-mentioned limitation on Kentucky Power's investment in the Hanging Rock-Jefferson line, there is no need for the rate base phase-in Kentucky Power had originally proposed. The rate-making limitation on investment, which also applies to operating expenses, reduces the rate impact of the line by more than 50 percent. The Commission must balance the needs of Kentucky Power with those of its consumers, and since the limitation on investment significantly lessens the rate impact of the Hanging Rock-Jefferson line, the need for the phase-in is obviated. The Commission must also be sensitive to Kentucky Power's concerns about its financial condition and its need to refinance approximately $50 million in short-term debt in late 1985 or early 1986. Therefore, in conjunction with the limitation on investment in the line, the Commission will allow Kentucky Power current recovery through rates of the allowable costs associated with the Hanging Rock-Jefferson line.

VALUATION

Kentucky Power presented the net original cost and capital structure as valuation methods in this case. The Commission has given due consideration to these and other elements of value in determining the reasonableness of the proposed rates.

Net Original Cost

In its original application Kentucky Power proposed a pro forma jurisdictional rate base of $632,657,790.[11] This amount included post-test year adjustments for the addition of the Hanging Rock-Jefferson line, the addition of the Rockport plant and reductions in fuel inventory. Subsequent to the Commission's Orders in Case Nos. 8271 and 8904 issued on August 2 and 3, 1984, respectively, Kentucky Power, in its amended exhibits filed August 23, 1984, proposed a pro forma jurisdictional rate base of $456,747,929 which eliminated all expenditures associated with its ownership of 15 percent of the Rockport plant.[12] The AG, through its witness, Mr. Robert Henkes, of the Georgetown Consulting Group, Inc., proposed a pro forma jurisdictional rate base of $394,514,424 which eliminated all expenditures associated with Kentucky Power's ownership of Rockport and also reflected the Commission's decision in Case No. 8904 to limit, for rate-making purposes, Kentucky Power's investment in the Hanging Rock-Jefferson line to only 44 percent of Kentucky Power's total investment therein.[13] Both Kentucky Power and the AG adjusted rate base to reflect changes occurring during the period from December 1984 to December 1985. The AG's proposal also reflected an adjustment to eliminate the amount of Construction Work in

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11 Financial Exhibit, Section V, Schedule 2, page 1.

12 Exhibit CRB-5, page 8 of 19, Revised.

13 Henkes Schedule 3, Revised.

Progress ("CWIP") for which Kentucky Power would be reimbursed by others.

The Commission, in accordance with its decision in Case No. 8904, has limited Kentucky Power's investment in the Hanging Rock-Jefferson line to 44 percent of the total investment; however, the Commission has reflected this limitation based on the projected December 1, 1984, rate base rather than use the 1984-1985 average proposed by Kentucky Power. The Commission finds it proper, in this case, to update the rate base beyond the end of the test year due to the addition of the Hanging Rock-Jefferson line; however, the Commission is not persuaded that it is proper or necessary to go beyond the approximate date of this Order in reflecting adjustments to the year-end rate base.

Kentucky Power proposed adjustments to reflect the proposed year-end depreciation expense adjustment in the accumulated provision for depreciation and to reflect its proposed expense adjustments in the calculation of cash working capital. The Commission concurs with the accumulated provision for depreciation and has modified the adjustment to working capital to reflect the pro forma operating expenses allowed herein.

The AG proposed to reduce Kentucky Power's proposed rate base by $276,701 to eliminate the amount of CWIP for which Kentucky Power would be reimbursed by others. The AG proposed such an adjustment in Case No. 8734, Kentucky Power's most recent rate case, which the Commission rejected citing the absence of an analysis of the ongoing balances in this account and the long-term level of reimbursements made to Kentucky Power.[14] In this case the AG's witness, Mr. Henkes, supplied a 9-year average for this account of $384,515; however, no evidence was submitted concerning the historical levels of reimbursements Kentucky Power has received. The Commission finds that the adjustment proposed by the AG is incomplete as it does not address the actual level of reimbursements Kentucky Power has received. Accordingly, the Commission has not accepted the AG's proposal.

All other elements of the net original cost rate base have been accepted as proposed by Kentucky Power. The net original cost rate base devoted to Kentucky jurisdictional operations is determined by the Commission to be as follows:

Utility Plant in Service	$ 520,558,841
Construction Work in Progress	3,898,160
Plant Held for Future Use	83,247
Total Utility Plant	$ 524,540,248
Add:	
Materials and Supplies	$ 34,923,034
Prepayments	156,419
Cash Working Capital	22,468,456
Dumont Test Site	465,695
Subtotal	$ 58,013,604
Less:	
Accumulated Depreciation	$ 129,442,626
Customer Advances and Deposits	3,805,056
Accumulated Deferred Taxes	52,474,781
Subtotal	$ 185,722,463
Net Original Cost Rate Base	$ 396,831,389

14 Case No. 8734, Order entered September 20, 1983, page 10.

Capital Structure

Mr. Coulter R. Boyle, III, Accounting Manager and Assistant Treasurer of Kentucky Power, proposed an adjusted end-of-test-year capital structure containing 55.74 percent long-term debt, 6.12 percent short-term debt and 38.14 percent common equity.[15] The test-year capital ratios were adjusted to remove the effects of Kentucky Power's ownership of Rockport. Mr. James A. Rothschild, principal in the Georgetown Consulting Group, Inc., and witness for the AG, also recommended using Kentucky Power's adjusted end-of-test-year capital structure.[16] The Commission is of the opinion that Kentucky Power's adjusted end-of-test-year capital structure is reasonable.

Kentucky Power proposed adjustments to reduce its test year-end capitalization to exclude its investment in property held in the name of Franklin Real Estate and its investment in non-utility property. Kentucky Power also proposed adjustments to reflect a reduction in fuel inventory and to exclude its investment in the Carrs Plant site in Lewis County, Kentucky. The Commission has accepted these adjustments along with Kentucky Power's adjustment to eliminate its investment in Rockport. Kentucky Power's final adjustment increased capitalization to reflect 100 percent of the investment in the Hanging

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15 Exhibit CRB-5, page 6 of 19, Revised.

16 Rothschild Prefiled Testimony, Schedule 1.

Rock-Jefferson line. These adjustments resulted in a pro forma jurisdictional capital structure of $437,763,368.[17]

The AG, through Mr. Henkes, proposed jurisdictional capital of $377,357,151 which reflected the adjustments proposed by Kentucky Power except for the inclusion of 100 percent of the Hanging Rock-Jefferson line.[18] The AG's capital structure reflected an adjustment to reduce capital by $60.1 million to reflect only 44 percent of the investment in the Hanging Rock-Jefferson line. The AG also recommended that capital be reduced by $276,701 to exclude the investment in CWIP for which Kentucky Power would be reimbursed. Both the AG's and Kentucky Power's adjustments for the Hanging Rock-Jefferson line reflected the average rate base for the period from December 1984 to December 1985.

The Commission, consistent with its decision in Case No. 8904, has adjusted Kentucky Power's capitalization to exclude approximately 56 percent of the investment in the Hanging Rock-Jefferson line and this adjustment is based on the December 1, 1984, rate base for the line. In addition, as stated in the preceding section, the Commission has not accepted the AG's adjustment for CWIP to be reimbursed by others. Taking into consideration the accepted adjustments, the Commission has

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17 Exhibit CRB-5, page 6 of 19, Revised.

18 Henkes Schedule 2, Revised.

determined Kentucky Power's jurisdictional capital for rate-making purposes to be as follows:

	Amount	Percent
Long-term Debt	$211,212,181	55.74
Short-term Debt	23,171,772	6.12
Common Equity	144,537,257	38.14
Total	$378,921,210	100.00

In determining the adjusted capital structure, the Commission allocated the adjusted Job Development Investment Tax Credit ("JDIC") to each capital component on the basis of the ratio of each component to total capital excluding JDIC.

REVENUES AND EXPENSES

For the test year Kentucky Power had jurisdictional net operating income of $54,199,409. Kentucky Power proposed several adjustments to its test period revenues and expenses which resulted in adjusted net operating income of $30,591,337.[19] The Commission is of the opinion that the proposed adjustments are generally proper and acceptable for rate-making purposes with the following exceptions:

Sales Growth

Kentucky Power did not propose an adjustment to reflect growth in sales above the test year level. However, Mr. Henkes sponsored an adjustment to increase revenues and expenses based upon customer growth experienced during the test year.

[19] Exhibit CRB-5, page 8 of 19, Revised.

The Commission is of the opinion that Mr. Henkes' proposed adjustment is deficient and unacceptable for rate-making purposes. Mr. Henkes' adjustment does not reflect full normalization of all customer classes by its exclusion of the customers served under the Quantity Power ("QP") tariff. This exclusion prevents an accurate determination of the revenues, expenses and KWH sales adjustments associated with the year-end level of customers served; therefore, the adjustment proposed by Mr. Henkes has not been utilized for rate-making purposes.

While the Commission has not accepted Mr. Henkes' adjustment in this instance, it does agree with its intent and the concept supporting such an adjustment. Kentucky Power is the only major generation and distribution electric utility under this Commission's jurisdiction which does not propose such an adjustment. The Commission is not persuaded by Kentucky Power's contention that the principle of a year-end customer adjustment is wrong. Nor does it believe that customer shifts between rate classes could not, in future cases, be incorporated in an adjustment of this type. The Commission is of the opinion that, in future cases, an adjustment of this type should be made. Kentucky Power is hereby directed, as of the date of this Order, to begin recording all customer shifts between rate classes and to be prepared to present this data as part of a year-end revenue normalization adjustment in its next rate case.

Employee Service Discounts

For several years Kentucky Power has given its employees a discounted service rate for their residential electric bills, and the tariff regarding this service has specifically stated that these discounts will not be allowed for rate-making purposes.[20] In this case Kentucky Power has changed its previous position and has proposed that its revenues be reduced to reflect the employee discounts. The AG, through Mr. Henkes, contested the inclusion of these discounts in the determination of revenue requirements as they represent an added benefit not required in Kentucky Power's labor contracts.

Kentucky Power offered no evidence that its employee discount is considered in its wage and benefits negotiations with its union employees or that it was considered in determining non-union wages and salaries. Although Kentucky Power and its employees may regard discounted electric service as an employee benefit, the record herein provides no evidence to convince the Commission that ratepayers should bear the cost of service discounts granted employees. Therefore, the Commission has increased Kentucky Power's jurisdictional operating revenues by $59,656 to eliminate the effect of employee discounts.

Unit Power Agreement

As discussed earlier in this Order, the Commission has found Kentucky Power's decision to enter into a unit power agreement in order to acquire 15 percent of the capacity of Rockport not in the best interests of its ratepayers. Therefore, the Commission has not accepted Kentucky Power's pro forma adjustment to increase its jurisdictional operating expenses by

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[20] Financial Exhibit, Section III, page 49 of 79.

approximately $37.1 million to reflect its annual cost under that agreement.

A separate entry which Kentucky Power included with the unit power adjustment reflected a $2.1 million reduction in operating expenses resulting from Kentucky Power's share of the profits from system sales of the Rockport capacity. Actually, this adjustment is based on Kentucky Power's MLR share of the system sales profit and is unaffected by the proposed unit power agreement adjustment or the Commission's denial thereof. Accordingly, the Commission has accepted the system sales profit adjustment as proposed without any modification.

The third component of Kentucky Power's proposed unit power agreement adjustment consisted of a $5.2 million decrease in its annual capacity equalization charges. This decrease would result from a reduction in Kentucky Power's capacity deficit within the AEP pool effected by its addition of the Rockport capacity. This adjustment reflected a decrease of 111 MW in Kentucky Power's monthly deficit times the March 1984 capacity rate of $3.91 times 12 months. Kentucky Power indicated that if it did not acquire additional capacity from Rockport or some other source, its annual capacity equalization charges would increase by $8.7 million.[21] Kentucky Power stated that this increase would be caused by (1) an increase in its capacity deficit with the addition of Rockport to the AEP system and (2) an increase in the capacity equalization

21 Response to PSC Data Request dated August 31, 1984, Item 3, page 1.

rate from $3.91 to $4.50 due to Indiana and Michigan Electric Company ("I & M") becoming a surplus capacity member due to the addition of Rockport.

KIUC and the AG opposed the use of the $4.50 rate. KIUC contended that the projected amount was not known and measurable and recommended that the test year-end rate of $3.91 be used. KIUC appears to have interpreted the Commission's known and measurable standard in a manner similar to the known and certain description Mr. Henkes used in detailing some of his adjustments. While it would be helpful to the Commission if all adjustments were certainties, such a scenario does not exist. The Commission ust address the relative accuracy of all adjustments taking into consideration the assumptions, if any, used in making the adjustment.

The AG maintained that the use of the $4.50 rate would require shifting the test year forward. The AG also argued that the use of the $4.50 rate would reflect increased equalization charges resulting from increased investment costs for the AEP system while no recognition was given to increased revenues to be produced by the new assets. The Commission is not persuaded by the AG's argument concerning a shift of the test year. The recognition of a changed capacity rate is, in effect, no different than recognizing a changed tax rate and such recognition is not limited by when the test year ended. The earlier adjustment concerning Kentucky Power's share of system sales profit from the Rockport plant, which the AG did not oppose, is contrary to each of the AG's arguments concerning the $4.50 capacity rate. That adjustment, like the $4.50 rate, reflects the addition of Rockport to the AEP system and its effect on Kentucky Power. Furthermore, that adjustment recognizes the additional revenues to be generated by the asset in question.

The Commission is of the opinion that the capacity rate of $4.50 is more representative of the rate Kentucky Power would pay without acquiring additional capacity than the $3.91 rate in effect in March 1984. The rate of $3.91 reflects only Ohio Power Company as a surplus member of the pool. If, for rate-making purposes, the Commission treats all of Rockport as I & M capacity, fairness requires that this treatment be applied consistently, whether such treatment is in favor of Kentucky Power's position or the positions of the intervenors. Therefore, in order to be consistent with its decision not to reflect the costs associated with the unit power agreement or treat any of the Rockport capacity as additional capacity for Kentucky Power, the Commission has made an adjustment to increase Kentucky Power's test year jurisdictional expense for capacity equalization charges by approximately $8.7 million.

Big Sandy Plant Maintenance Expense

Kentucky Power proposed an adjustment of $878,132 to increase Kentucky jurisdictional production plant maintenance expense to a "levelized" amount. The proposed adjustment, which reflects a total of $10.7 million of production plant maintenance expense, was sponsored by Mr. Herbert Bissinger, Assistant Manager of the Plant Maintenance Division of the AEP Service Corporation.

In calculating the adjustment, Mr. Bissinger employed the same methodology used in Kentucky Power's most recent rate case, Case No. 8734.[22] In that case, the Commission rejected the proposed adjustment and utilized the actual test year expense for rate-making purposes.[23] In this case, Kentucky Power did not alter its methodology nor did it respond to the Commission's concerns regarding the analysis of different types of maintenance expense except to say that such an analysis would be a costly and complex undertaking.[24]

In its brief, Kentucky Power maintained that the Commission's position has been that by filing annual rate cases Kentucky Power could fully recover its costs, subject to regulatory lag. Kentucky Power has inferred this position; the Commission has stated that frequent rate proceedings, as has been Kentucky Power's recent history, should make any over- or under-recovery of production plant maintenance expense short-lived. The frequency of Kentucky Power's rate filings is dependent upon its overall revenue needs as determined by its management. Production plant maintenance expense is but one factor in the determination of Kentucky Power's revenue requirements which the Commission must analyze. Inasmuch as Kentucky Power's plant maintenance expense represents less than 6 percent of its annual revenues, it is improbable that the

22 T.E., Volume III, October 11, 1984, page 11.

23 Case No. 8734, Order entered September 20, 1983, page 20.

24 Bissinger Prefiled Testimony, pages 7-8.

fluctuation of that expense, by itself, would create the need for annual rate applications.

The Commission is of the opinion that the proposed adjustment does not result in a more representative level of plant maintenance expense, but rather, it would result in an ever-increasing level of expense which would perpetuate itself in years to come. Therefore, the Commission hereby reaffirms the decision it made in Case No. 8734 and again rejects the adjustment proposed by Kentucky Power for production plant maintenance expense. The Commission will allow for rate-making purposes the actual test year expense of $9.8 million.

Wages and Salaries Expense

Kentucky Power proposed two adjustments to wages and salaries expense. The first adjustment, an increase of $944,704, reflected the wage and salary levels in effect at the end of the test period. The second adjustment, an increase of $978,626 reflected the wage and salary increases scheduled to occur from the end of the test year through December 31, 1984. These adjustments reflect general, merit, time progression and promotional increases in employees' salaries and wages.

The timing of these adjustments is primarily the result of a wage and salary freeze Kentucky Power imposed on its employees in January 1983. The freeze, which was lifted in October 1983, has caused several wage and salary changes that were deferred to become effective during the latter part of 1983 and the early months of 1984. In view of the unusual circumstances regarding these increases, the Commission is of the opinion that the adjustment of approximately 5 percent to annualize year-end wage and salary levels is reasonable and appropriate for rate-making purposes. Furthermore, due to the unusual circumstances caused by the wage and salary freeze, the Commission is of the opinion that post-test year adjustments occurring through May 1984 are appropriate and properly includable in the determination of revenue requirements. These adjustments, representing an overall increase of approximately 3.8 percent, reflect Kentucky Power's usual May 1 general increase to non-exempt employees, were in effect prior to the filing of this case and are fully known and measurable. However, the Commission will not accept the portion of the post-test year adjustment based upon merit increases budgeted for the period from June through December 1984. Although Mr. Boyle testified that these increases would, without fail, be granted during the time the current budget was in effect,[25] by definition merit increases are not a certainty. Adjustments such as this, for projected increases occurring 3 to 9 months beyond the end of the test year, are not sufficiently known and measurable to be included in the determination of revenue requirements. Therefore, the Commission has reduced Kentucky Power's proposed adjustment for post-test year wage and salary increases by $297,081 to $681,545.

25 T.E., Volume III, October 11, 1984, pages 237-238.

Employee Benefits

Kentucky Power proposed several adjustments to increase its operating expenses by a total of $776,212 to reflect increases in payroll taxes, insurance and various other employee benefits. The AG, through Mr. Henkes, proposed adjustments to reduce this amount by $261,134 to reflect the refunds of premiums and reduced payments Kentucky Power has received in the past due to favorable claim experience for life insurance, long-term disability insurance and group medical insurance.[26] For life insurance and long-term disability insurance, Mr. Henkes' adjustments reflected Kentucky Power's experience with refunds and reduced payments over the past 3 to 5 years. Although Kentucky Power claims that continued favorable claims experiences are not assured, it is probable, based on past experience, that favorable experiences will continue to occur. Should adverse claims experience in the future lead to additional assessments against Kentucky Power, those costs will be addressed in subsequent rate proceedings. At this time, however, favorable claims experience and the associated reduced costs have been the rule, not the exception. Therefore, the Commission has accepted Mr. Henkes' adjustments to life insurance and long-term disability insurance which reduce Kentucky Power's pro forma insurance expense by $100,754.

The remaining $160,380 of Mr. Henkes' adjustments reflected his proposed decrease in Kentucky Power's expense for group

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[26] Henkes Schedules 12, 13 and 14.

medical insurance. Mr. Henkes based this adjustment on Kentucky Power's favorable claims experience during the test year which resulted in the elimination of two monthly premium payments. The record herein does not show the consistent trend of favorable claims experience for group medical insurance as shown for life and long-term disability insurance. Without such a trend, the Commission is of the opinion that Kentucky Power's adjustment, which annualizes the year-end monthly expense, is appropriate and should be accepted for rate-making purposes. Therefore, such adjustment has been accepted and Mr. Henkes' adjustment has been denied.

In addition to the above adjustments, the Commission has reduced Kentucky Power's pro forma adjustment to increase FICA expense based upon the full amount of its proposed post-test year wage and salary adjustment. In conjunction with its rejection of the adjustment for merit increases projected to occur after the filing of this case, the Commission has made a proportionate adjustment to reduce the amount of Kentucky Power's post-test year FICA adjustment by $18,866, from $62,183 to $43,317.

The net effect of the adjustments to employee benefits expense is an increase of $656,592 above the level of expense incurred during the test year.

Hanging Rock-Jefferson Operating Expenses

Kentucky Power proposed to include the full amount of $2.6 million in operating expenses projected for the Hanging Rock-Jefferson transmission line. The AG, through Mr. Henkes, proposed an adjustment to increase operating expenses by only $1.1 million to reflect the Commission's decision in Case No. 8904 to limit Kentucky Power's recovery, through rates, to 44 percent of the investment and costs associated with the Hanging Rock-Jefferson line. Mr. Henkes made no provision for the tax benefits generated by the Hanging Rock-Jefferson line during the test year or the fact that said benefits required modification as a result of the rate-making limitations imposed through Case No. 8904. As Mr. Boyle indicated, it would be improper to reflect 100 percent of those tax benefits in the cost of service if 100 percent of the costs are not reflected.[27] The Commission concurs with this assessment and, therefore, has made an adjustment to increase Kentucky Power's cost of service by $618,431, which represents 56 percent of the tax benefits associated with the Hanging Rock-Jefferson line.[28]

Parent Company Tax Loss

Historically, AEP has generated significant tax losses which it allocates to its subsidiaries. Prior to Case No. 8734, Kentucky Power had reduced its cost of service through the inclusion of these losses. Since that time Kentucky Power has reversed its previous position and has argued that its share of the AEP tax loss should not be reflected in the cost of service. Kentucky Power's present position is that AEP's shareholders, and

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27 T.E., Volume IV, October 12, 1984, page 129.

28 Response to PSC Data Request dated August 31, 1984, Item 1, page 22.

not the subsidiary ratepayers, have paid for the expenses which created the tax loss and they should receive the benefit of the reduced taxes.[29]

The Commission is not persuaded by this argument. The facts as they exist now are the same as in Case No. 8734. AEP, as a parent company, generates little, if any, revenues unrelated to the operation of its subsidiaries. Likewise, AEP incurs little, if any expense not related to the operation of its subsidiaries. Were it not for AEP's subsidiaries, there would be no reason for AEP to exist. It follows, therefore, that the expenses incurred by AEP are a direct result of the operation of its subsidiaries and the benefit of a tax reduction created by those expenses should flow to those subsidiaries.

The Commission, contrary to Kentucky Power's assertion, does not dispute the legitimacy of the argument that ratepayers should be required to pay for the parent company's tax expense, if and when such an expense is incurred. Such an argument is entirely consistent with the Commission's usual rate-making procedures concerning parent/subsidiary tax allocations. Therefore, absent any substantive evidence to support a different decision than the one reached in Case No. 8734, the Commission has made an adjustment to reduce Kentucky Power's federal income tax expense by $168,624 to reflect its portion of the tax loss generated by AEP.

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29 Boyle Prefiled Testimony, page 20.

Charitable Contributions

Kentucky Power proposed an adjustment to increase operating expenses by $30,581 to reflect the expense for charitable contributions made during the test year in its cost of service. Kentucky Power maintained, as it has in previous cases, that these contributions were a necessary part of being a responsible corporate citizen and should, therefore, be included in its cost of service for rate-making purposes. The record herein includes no substantive evidence to show that these contributions benefit Kentucky Power's customers. The Commission has consistently denied the inclusion of charitable contributions as an operating expense for rate-making purposes and finds that Kentucky Power has presented no evidence in this proceeding to cause a departure from this policy. Therefore, the adjustment to include this expense in the cost of service has been denied.

Rate Case Expense

Kentucky Power's rate case expense during the test year was $183,061. Kentucky Power proposed an adjustment to reduce this amount by $18,527 to $164,534. This adjustment reflected the proposed 2-year amortization of the sum of (1) $58,905 remaining from the amortization of rate case expenses authorized in Case No. 8734, (2) the difference of $85,163 between Kentucky Power's estimated expense for Case No. 8734 of $100,000 and its actual expense of $185,163, and (3) the estimated cost of $185,000 for the instant case.

The AG, through Mr. Henkes, argued against Kentucky Power's inclusion of the differences between the actual and estimated amounts for Case No. 8734 on the grounds that such inclusion would constitute retroactive rate-making. Furthermore, Mr. Henkes argued that it was inappropriate to use the expense incurred for the last case as the basis for the current estimate.

The Commission agrees with Mr. Henkes concerning the retroactive nature of the proposed recovery of the $85,163 difference between the estimated and actual expense incurred for Case No. 8734. It is inappropriate to compare the actual amount of a past expense with the amount for that expense item that was used in setting rates and include the difference as an expense in setting current rates.

The Commission does not agree with Mr. Henkes' argument concerning the expense level for the current case. The issues in this case are no less complex than in the prior case and the number of data requests and witnesses required are no less complex or voluminous. Therefore, the Commission is of the opinion that the proper adjustment for rate case expense should reflect the sum of the $58,905 remaining from Case No. 8734 and the $185,000 expense estimated for this case, for a total of $243,905. The resulting annual rate case expense allowed for rate-making purposes is $121,953 which results in an adjustment to reduce the test year rate case expense by $61,108.

Storm Damage Expense

Mr. Henkes proposed an adjustment to reduce Kentucky Power's test year expense for storm damage by $29,027 based on Kentucky Power's historical expense levels for the past 9 years, adjusted to current dollars. Kentucky Power argued that the 9-

year average was inappropriate because the selection of the time period was arbitrary and because during those 9 years the same standards had not been consistently applied in determining what constituted storm damage expense. Finally, Kentucky Power contended that, since this type of adjustment was first proposed by the AG in Kentucky Power's last rate case, the magnitude of any adjustment should be limited to the average expense of only the 2 most recent calendar years.

The Commission is of the opinion that the adjustment proposed by Mr. Henkes is entirely proper and acceptable for rate-making purposes. The adjustment utilizes the same methodology as was accepted by the Commission in Kentucky Power's last rate case and Kentucky Power presented no argument against the adjustment that had not been made in the prior case. Therefore, Kentucky Power's test-year expense had been reduced by $29,027.

Coalton-Leon Line

Mr. Henkes proposed an adjustment to reduce Kentucky Power's test year expense by $33,922 to eliminate the jurisdictional cost associated with surveying work as part of Kentucky Power's plans to rebuild the Coalton-Leon line. After the plans to rebuild the line were cancelled, Kentucky Power expensed the cost of the surveying work. Mr. Henkes proposed to eliminate this item for rate-making purposes on the grounds that the costs associated with an abandoned project should not be charged to ratepayers.

Kentucky Power maintained that the plans to rebuild the line had not been abandoned and that, sometime in the future, it could determine that the line should be rebuilt. Kentucky Power also argued that surveying work, such as that done for the Coalton-Leon line, is not a one-time event, but rather, is performed on a regular, ongoing basis and constitutes a legitimate expense for rate-making purposes.

The Commission is of the opinion that, if and when Kentucky Power revives its plan to rebuild the Coalton-Leon line, all reasonable capital costs incurred therein should be recovered through depreciation charges after the rebuilt line is placed in service. Furthermore, while surveying work such as that done for the Coalton-Leon line may be done on an ongoing basis, none of the evidence presented by Kentucky Power indicates that the expensing of such costs, due to cancellation or deferral of a project, is a regular occurrence. Therefore, the Commission has accepted the adjustment proposed by Mr. Henkes and has reduced Kentucky Power's test-period operating expenses by $33,922.

Carrs Site Property Taxes

Mr. Henkes proposed an adjustment to reduce Kentucky Power's test-period operating expense by $51,189 to eliminate, for rate-making purposes, the test year property tax expense associated with the Carrs site in Lewis County, Kentucky. Kentucky Power had excluded its investment in the site from rate base and capitalization, and, in response to a data request from the AG, had confirmed that its property tax expense should not include this expense item.[30] The Commission, therefore, has reduced Kentucky Power's operating expense by $51,189 for rate-making purposes.

Adjustment to AFUDC

Kentucky Power proposed an adjustment to decrease AFUDC by $15,256,444 to $157,911 based on the year-end level of CWIP and the 12.98 percent overall requested rate of return. The AG, through Mr. Henkes, proposed an adjustment which reduced AFUDC by $15,268,208 to $146,147 based on Mr. Rothschild's recommended overall rate of return of 12.03 percent.

The Commission has adjusted AFUDC based on the overall rate of return allowed herein of 12.6 percent. This results in an adjusted level of AFUDC of $153,072 which reflects a decrease of $15,261,283.

Interest Synchronization

Kentucky Power proposed an adjustment to increase state and federal income taxes by $2,116,936 to reflect the pro forma decrease in annual interest expense. In determining the amount of the adjustment, Kentucky Power applied long-term and short-term debt interest rates of 10.2 percent and 10.18 percent, respectively, to its proposed adjusted level of those capital components excluding any allocation for JDIC. Kentucky Power disagrees with the Commission's practice of assigning JDIC to all components of the capital structure and treating the interest cost associated with debt capital as a deduction in computing federal

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30 Response to AG Request No. 1, Item 51(b).

income tax. In support of its argument, in its post-hearing brief, Kentucky Power referred to a recent action by the Internal Revenue Service ("IRS") to disallow all JDIC utilized by Union Electric Company ("Union") in tax years 1978, 1979, and 1980 specifically as the result of interest synchronization by the Missouri Public Service Commission which imputes tax deductible interest to JDIC. Prior to filing its brief, Kentucky Power had indicated that it would abide by the Commission's reaffirmation, in this case, of its decision in Case No. 8734 to continue its interest synchronization treatment pending final judicial decisions on this issue involving other utilities under the Commission's jurisdiction.

By the untimely nature of the filing of this information, neither the Commission nor the intervenors are afforded an opportunity to address this matter fully. Moreover, the reference in Kentucky Power's brief does not indicate that the interest synchronization method used by the Missouri PSC is identical or even similar to the methodology used in Kentucky. The Commission does not regard Kentucky Power's reference to the proposed IRS action against Union as credible evidence to be considered in this proceeding. Therefore, the Commission will reiterate its position on JDIC which remains unchanged from Kentucky Power's last rate case. The Commission is of the opinion that its treatment of JDIC is consistent with IRS regulations and such treatment will be continued herein. However, in court cases involving other utilities subject to this Commission's jurisdiction, should the final judicial opinions on this issue be adverse to the

Commission's position, the Commission shall recognize such opinions. Thereafter, upon its receipt of an appropriate application by Kentucky Power, the Commission will order a rate adjustment to generate the associated revenues which have been denied herein.

In accordance with its stated position, the Commission has applied the applicable cost rates to the JDIC allocated to the debt components of the capital structure. Using the adjusted capital structure allowed herein, the Commission has computed an adjustment to decrease interest by $6,145,775 which results in an increase of $3,026,180 to income taxes.

After applying the combined state and federal income tax rate of 49.24 percent to the accepted pro forma adjustments, the Commission finds that operating income should be adjusted as follows:

	Actual Test Year	Adjustments	Adjusted Test Year
Operating Revenues	$195,439,165	$ 945,238	$196,384,403
Operating Expenses	156,654,111	7,131,161	163,785,272
AFUDC Offset	15,414,355	<15,261,283>	153,072
Net Operating Income	$ 54,199,409	$<21,447,206>	$ 32,752,203

RATE OF RETURN

Mr. Boyle recommended an adjusted embedded cost of 10.2 percent for long-term debt and a 10.18 percent cost for short-term debt.[31] The embedded cost of long-term debt was adjusted to reflect a reduction in long-term debt due to Kentucky Power's sale

31 Exhibit CRB-5, page 6 of 19, Revised.

of its interest in Rockport. The cost of short-term debt was the actual test year interest cost incurred by Kentucky Power. Mr. Rothschild also recommended using a 10.2 percent cost for long-term debt and a 10.18 percent cost for short-term debt.[32] The Commission is of the opinion that these costs are reasonable.

Mr. Carl H. Seligson, Managing Director of Merrill Lynch, Pierce, Fenner & Smith, Incorporated, and witness for Kentucky Power, recommended a 19 percent return on equity based on a risk premium analysis.[33] He derived his 6.1 percentage points risk premium from an Ibbotson & Sinquefield study.[34] Mr. Seligson then added the risk premium to the yield on 30-year Treasury Bonds to determine the required rate of return on equity for Kentucky Power.[35] Dr. James N. Giordano, assistant professor of economics at Villanova University and witness for Kentucky Power, recommended a 17.5 percent return on equity based on a discounted cash flow ("DCF") analysis and a capital asset pricing model ("CAPM").[36] He determined the cost of equity to AEP, using those techniques, and then adjusted the results to reflect the risk differential between Kentucky Power and AEP.[37]

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32 Rothschild Prefiled Testimony, Schedule 1.

33 Seligson Prefiled Testimony, page 27.

34 T. E., Volume II, October 10, 1984, page 65.

35 Seligson Prefiled Testimony, Exhibit No. CHS 5, page 1.

36 Giordano Prefiled Testimony, page 32.

37 Ibid., pages 31 and 32.

In their study, Ibbotson and Sinquefield used earned returns on common stock to derive the historical risk premium between bonds and stocks.[38] However, the actual investor required risk premium is the spread between bond yields and the expected return on common stock. If the earned return on equity varies from the expected return, the derived risk premium will not equal the investor required risk premium. At the hearing, Mr. Seligson agreed that the risk/return relationship between stocks and bonds varied over time.[39] The Commission is skeptical that the investor required risk premium can be accurately quantified using historical data. The Commission remains unconvinced of the validity and usefulness of the risk premium analysis.

Dr. Giordano used a 14.4 percent dividend yield (based on AEP's $16.50 market price in mid-May, 1984) in his DCF analysis.[40] However, AEP's current market price is $20.25 per share, as quoted in the November 12 issue of the Wall Street Journal. AEP's market price has not been below $19 per share since September 19, 1984.[41] Dr. Giordano's 14.4 percent dividend yield also includes an adjustment to recognize the 5 percent discount in price received by participants in AEP's dividend reinvestment plan.[42]

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[38] T. E., Volume II, October 10, 1984, page 65.

[39] Ibid., page 71.

[40] Giordano Prefiled Testimony, page 13.

[41] T. E., Volume II, October 10, 1984, page 120.

[42] Giordano Prefiled Testimony, page 13.

participants in the plan receive a bonus in that they can purchase new shares of AEP's common stock at a 5 percent discount. The effect is to increase the real dividend received by participants in AEP's dividend reinvestment plan. The Commission is of the opinion that Dr. Giordano has overstated AEP's dividend yield. Using a more reasonable dividend yield in Dr. Giordano's DCF analysis will result in a lower required return on equity.

Dr. Giordano used the same 6.1 percent risk premium that Mr. Seligson used in his risk premium analysis. The risk premium has the same drawbacks when used in a CAPM analysis as when used in a standard risk premium analysis. The Commission also questions Dr. Giordano's selection of the risk-free rate. Dr. Giordano used the yield on long-term government bonds as the risk-free rate in his CAPM.[43] However, long-term debt of any kind has more inflation risk than short-term debt because long-term debt is potentially exposed to inflation for longer periods of time. Investors consider short-term debt to be less risky than long-term debt as evidenced by a generally positively sloped yield curve. Short-term treasury bills generally yield less than long-term treasury bonds. The Commission is not convinced that Dr. Giordano's CAPM analysis accurately represents the investor required return on equity for AEP or Kentucky Power.

Mr. Rothschild recommended a 15 percent return on equity based on a DCF analysis of a group of non-nuclear electric

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43 Ibid., page 19.

utilities and a comparable earnings study.[44] The non-nuclear utilities are companies in Moody's 24 Electric Utilities index that are not currently involved in nuclear construction.[45] Mr. Rothschild also examined the earnings of a group of industrial companies with an achieved market to book ratio close to 1.[46] He did not perform a risk premium analysis because he was of the opinion that it has begun to overstate the required return on equity.[47] The Commission has certain reservations regarding Mr. Rothschild's analysis. Mr. Rothschild selected companies for his comparable earnings analysis from a group of 900 industrials followed by Standard & Poor's, with the only criterion for selection being a market to book ratio between .9 and 1.1.[48] No allowances were made for differences in capital intensity, competition or other factors. The Commission is not convinced that such a diverse group of industrial companies is comparable to Kentucky Power or AEP.

Mr. Rothschild estimated a 3.46 to 4.46 percent growth rate for his non-nuclear composite, based on the retention rate times the return on equity ("b x r") method.[49] The return on equity

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44 Rothschild Prefiled Testimony, page 1.

45 Ibid., page 17.

46 Ibid., page 22.

47 Ibid., page 25.

48 Ibid., page 22.

49 Ibid., Schedule 3, page 1b.

portion of the growth rate was an estimate of what investors expected the group of companies to be able to earn in the future.[50] Mr. Rothschild used an estimated return on equity to calculate the growth rate to be used in a DCF estimate of the required return on equity. This appears to be circular reasoning. The Commission is also of the opinion that Mr. Rothschild's DCF analysis understates the required return on equity for Kentucky Power. A growth rate developed mechanically, using the b x r method, may not accurately represent investor expectations for a given time horizon. The average estimated dividend growth rate for Mr. Rothschild's non-nuclear electrics is 6 percent, according to Value Line.[51] The average estimated earnings growth rate for the group is 5.3 percent, according to Value Line.[52] Using Value Line's projected growth rates in Mr. Rothschild's DCF analysis will produce a higher indicated return on equity for the group of non-nuclear electric utilities. The Commission is concerned that Mr. Rothschild's recommended return on equity is inadequate in light of the financial difficulties confronting Kentucky Power.

The Residential Intervenors recommended that the rate of return on equity for Kentucky Power be no higher than 14.75 percent.[53]

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50 T. E., Volume IV, October 12, 1984, page 120.

51 Ibid., page 122.

52 Ibid., page 123.

53 Residential Intervenors' Brief, page 14.

Kentucky Power's fixed charge coverage ratio under its mortgage indenture has improved from 2.51 times in 1983 to 2.59 times as of March, 1984.[54] However, this coverage ratio still provides only a slim margin of financial flexibility. Without rate relief, Kentucky Power's First Mortgage Bond interest coverage ratio would fall below 1, based on projected load growth and operating expenses for 1985.[55] Incorporating the AG's recommended rate relief, including Mr. Rothschild's 15 percent return on equity, would reduce Kentucky Power's First Mortgage Bond interest coverage ratio to 2.35 times, on a pro forma basis.[56] The 1983 interest coverage ratio, including AFUDC, for Moody's Electric Utility average was 3.17 times.[57] Clearly, Kentucky Power's coverage ratio is not up to par with the average electric utility.

Capital costs are currently only slightly lower than they were a year ago. Baa-rated utility bonds are yielding 13.81 percent while one year ago they were yielding 14.07 percent.[58] The Commission is not prepared to forecast Federal Reserve policy nor the movement of capital costs. Kentucky Power continues to

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54 Response to PSC Data Request Dated June 6, 1984, Item 5, page 1.

55 Kentucky Power's Response to Oral Request No. 3, page 4.

56 <u>Ibid.</u>

57 Moody's Public Utility Manual, 1984, Volume 1, page a14.

58 Moody's Public Utility News Reports, November 6, 1984, page 2285.

have a highly leveraged capital structure, containing over 61 percent debt. Clearly, Kentucky Power continues to face significant risk and marginal financial integrity.

The Commission finds no compelling evidence to reduce Kentucky Power's rate of return on equity. Therefore, after considering all the evidence, including Kentucky Power's current financial condition, the Commission is of the opinion that a range of returns on equity of 16 to 17 percent is fair, just and reasonable. A return on equity in this range would not only allow Kentucky Power to attract capital at reasonable costs to insure continued service and provide for necessary expansion to meet future requirements, but also would result in the lowest possible cost to the ratepayer. A return on common equity of 16.5 percent will allow Kentucky Power to attain the above objectives.

Rate of Return Summary

Applying rates of 16.5 percent for common equity, 10.2 percent for long-term debt and 10.18 percent for short-term debt to the capital structure approved herein produces an overall cost of capital of 12.6 percent and provides a rate of return on net investment of 12.03 percent. The Commission finds this overall cost of capital to be fair, just and reasonable.

REVENUE REQUIREMENTS

The Commission has determined that Kentucky Power needs additional operating income of $15 million to produce a rate of return of 16.5 percent on common equity based on the adjusted historical test year. After the provision for state and federal income taxes, there is an overall revenue deficiency of $29.6

million which is the amount of additional revenue granted herein. The net operating income required to allow Kentucky Power the opportunity to pay its operating expenses and fixed costs and have a reasonable amount for equity growth is $47,751,176. The required operating income and the increase granted herein are as follows:

Net Operating Income Found Reasonable	$47,751,176
Adjusted Net Operating Income	32,752,203
Net Operating Income Deficiency	$14,998,973
Additional Revenue Required	$29,618,472

The additional revenue granted herein will provide a rate of return on net original cost of 12.03 percent and an overall return on total capitalization of 12.6 percent.

OTHER ISSUES

Coal Inventory

Kentucky Power proposed to include a coal inventory valued at $28,206,081 in the rate base, for the test year ended March 31, 1984. The inventory consisted of 754,379 tons at a weighted average cost of $37.39 per ton. In Kentucky Power's most recent rate case the Commission acknowledged the steps taken by Kentucky Power to manage its coal inventory, but the Commission stated that it ". . . expects Kentucky Power to develop a formal cost-benefit analysis of its coal inventory level (inventory model) and to incorporate such an analysis into future rate applications in support of its target coal inventory level."[59]

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[59] Case No. 8734, Order entered September 20, 1983, pages 11 and 12.

As directed by the Commission, Kentucky Power sought to obtain a coal inventory model which could be used to perform a formal cost-benefit analysis to determine its optimal coal inventory level. Kentucky Power decided to utilize the model proposed by Louisville Gas and Electric Company in Case No. 8924, General Adjustment in Electric and Gas Rates of Louisville Gas and Electric Company. The coal inventory model was run under two scenarios, on an AEP System basis and for Kentucky Power standing apart from the AEP System. Mr. Frank A. Brancato, Manager of Regulatory Affairs for AEP, concluded that the analyses are more appropriately done on an overall AEP System basis.[60] The coal inventory model utilized by Kentucky Power recognizes the timing of the United Mine Workers of America ("UMWA") labor contract strikes as a major contingency which necessitates the use of cyclical target coal inventory levels. Thus, Kentucky Power recommended the inclusion of the following coal inventory in rate base:

> Using the AEP System average inventory level of 95 days in the first year, 105 days in the second year, and 115 days in the third year of a three year UMWA wage agreement equates to an average coal inventory level of 754,425 tons for 105 days.[61]

Using the 13-month average test period burn rate of approximately 7,900 tons per day,[62] Kentucky Power's recommended coal inventory level equates to 95-days' burn.

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60 Brancato Prepared Testimony, pages 10-12.

61 Ibid., page 19.

62 Response to Commission Order dated June 6, 1984, Item No. 45C.

In this proceeding, the Commission has reviewed the test year-end coal inventory level, Kentucky Power's recommended coal inventory level and the coal inventory model used to arrive at its recommendation, and determined that Kentucky Power's proposed coal inventory level of 754,379 tons at a weighted average cost of $37.39 per ton should be accepted. The Commission is cognizant of the steps Kentucky Power has taken to determine its optimal coal inventory level and is pleased that Kentucky Power is striving to manage its coal inventory. Considering the high costs of financing coal inventory today, it is imperative that Kentucky Power be sensitive to inventory control. Kentucky Power is beginning to demonstrate the sensitivity which the Commission expects to continue into the future.

Rate Design

Kentucky Power proposed no change in its residential rate structure, but requested increases to the customer charge and initial rate block to recover customer cost from its fully allocated cost study. The Residential Intervenors objected to the customer charge and the two-step declining block structure. The Residential Intervenors objected to the proposal to increase the present $3.60 monthly charge to a $7.00 monthly charge and recommended that the customer charge be eliminated and the two-step energy charge be reduced to a flat rate KWH charge. The Residential Intervenors relied on Kentucky Power's marginal cost study and the testimony presented by Dr. John Stutz, witness for the Appalachian Research and Defense Fund of Kentucky, Inc., in Administrative Case No. 203, the Determinations with Respect to the Ratemaking Standards Identified in Section 111(d)(1)-(6) of the Public Utility Regulatory Policies Act of 1978. Although the Commission is of the opinion that marginal cost data should be considered in rate design, it does not agree to base residential rate design solely on marginal costs and Dr. Stutz's proposed method of scaling back marginal costs to an embedded cost revenue requirement. The Commission, being so advised, is of the opinion that the current rate design of Kentucky Power is just and reasonable but that the proposed increase to the Residential customer charge is unjust. Therefore, the Commission has adjusted the Residential customer charge to $4.25 per month.

Kentucky Power proposed changing the QP tariff from the current 30 minute measurement of billing demand to a 15 minute measurement. Kentucky Power stated that such a change will more accurately measure customer demand and that the GS and LGS tariffs have used 15 minute demand metering for many years.[63] The KIUC objected to the change and stated the change should be at the same time as the other large users on the AEP system are put on the same measurement. The other members of the AEP system are not in the Commission's jurisdiction. The Commission is concerned with equitable metering of billing demand for utilities and customers under its jurisdiction. The record is clear that use of a 15-minute peak demand measurement reduces the practice of "peak-splitting." The Commission, being so advised, is of the

63 Bibb Prefiled Testimony, page 18.

opinion that the proposed change will more accurately measure demand billing and should be incorporated into the QP tariff.

Class Cost of Service Studies

Kentucky Power presented two witnesses concerning class cost of service studies. Mr. Dennis Bethel, a Senior Rate Analyst in the Rate Research and Design Division of AEP, filed an embedded non-time-differentiated cost of service study. The study allocated capacity-related cost among customer classes using the average of the 12 monthly coincident peaks (12CP) of each class. Mr. Bethel's study also allocated customer and energy costs to the customer classes. In the past, Kentucky Power has used the 12CP class cost of service study for revenue allocation and for the design of rates. In this case, Kentucky Power has not relied on the 12CP class cost of service study for revenue allocation or rate design. The 12CP study was provided in this case to give an historical perspective and because the time-differentiated ("TOD") class cost of service study uses the same customer and energy cost classification and allocation, and demand cost classification as the 12CP study.

Mr. Mark Berndt, a Rate Analyst in the Rate Research and Design Division of AEP, filed a TOD class cost of service study. The TOD study differs from the 12CP study in the allocation of the demand or capacity related costs to the customer classes. The allocation of the demand cost in the TOD study involves a two step process. First, the costs must be classified as peak or off-peak period related. Then these components of the demand related costs are allocated to the customer classes using time-differentiated demand allocation factors. The development of the more sophisticated time-differentiated study has been facilitated by the increased computerization of AEP's load research program.

In the TOD class cost of service study presented in this case, two methods are combined to assign demand related costs to time periods. One method is the full availability dispatch ("FAD") method. This method attempts to measure how the existing capacity is presently used during each hour of the year. The second method is the loss of load probability ("LOLP") method. This method attempts to determine the expected reliability of the capacity to meet load in each hour of the year. Kentucky Power prefers a combination of these two methods because the FAD method gives recognition to how current capacity is actually being utilized while the LOLP method gives recognition to how load growth will affect system reliability. Mr. Bethel states that his preference for combining the FAD and LOLP methodologies derives from the fact that "[r]ates can be designed that will treat customers in an equitable manner while encouraging load management."[64]

In Case No. 8734, Kentucky Power presented the results from six different TOD class cost of service studies. At that time, a preference for the combination of the FAD and LOLP methods was stated. However, in that case the combination of the methods was accomplished by a 50-50 weighting of the results from each method. In this case the results from the LOLP method are weighted by 75 percent while the FAD results are weighted by 25 percent.

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64 Berndt Prefiled Testimony, page 11.

Kentucky Power in this case has proposed to give an increased weighting to the forward looking LOLP method.

In cross-examination of Kentucky Power witnesses, KIUC challenged the increased weighting on the LOLP method in this case.[65] In particular, KIUC objected to using the TOD study for the design of time-of-day rates. The 75-25 weighting proposed by Kentucky Power gives a greater weight to the on-peak demand allocation than the previous 50-50 weighting.

The Commission agrees with the 75-25 weighting used in the TOD class cost of service study. The increased emphasis of the forward-looking LOLP method is appropriate especially for Kentucky Power's efforts to encourage load management. Further, the Commission finds the TOD class cost of service is reasonable and should be used as a reference for determining revenue allocation and for the design of time of day rates.

Marginal Cost of Service

Pursuant to the Order in Administrative Case No. 203 Kentucky Power filed a marginal cost study in this case. Mr. Berndt sponsored the study. The study includes marginal demand, energy and customer costs.

In Administrative Case No. 203, the Commission ordered that marginal cost studies be filed in rate cases because it believed marginal costs were a valuable input to the rate design issues facing the companies. For instance, the question arose of whether the energy charge recovered at least the marginal energy cost to

65 T.E., Volume III, October 11, 1984, pages 56 and 78.

generate the kilowatt-hour. A review of the marginal energy cost and the proposed tariff is required to answer this question. In this case, the marginal energy cost for both on-peak and off-peak are provided.[66] The on-peak marginal energy costs range from 1.82 cents per kilowatt-hour for large industrial customers to 2.14 cents per kilowatt-hour for residential customers. The off-peak marginal energy costs range from 1.57 cents per kilowatt-hour to 1.88 cents per kilowatt-hour. When one compares these values to the tariffs, in all cases the energy charge is greater than the marginal energy costs. Thus, Kentucky Power is always recovering at least its marginal energy cost.

Mr. Berndt also stated that a marginal cost study can be useful in "looking at promotional rates."[67] In fact, in response to a staff data request it was apparent that Kentucky Power had compared the energy charge in its proposed residential load management tariff to the marginal energy cost to make certain that the energy charge recovered its marginal energy costs.[68]

Further, the marginal cost study would be useful in the development of cogeneration and small power production rates. As previously ordered, these rates will be further considered in future rate cases.

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66 Berndt Prefiled Testimony, page 43.

67 T.E., Volume III, October 11, 1984, page 110.

68 Response to Item 17, page 3 of 3, Commission Second Data Request.

The Residential Intervenors through cross-examination and their brief supported the position of "recovering costs first by pricing energy and demand components of rates at their appropriate marginal costs."[69] After these costs are accounted for then any remaining class revenue requirement would be recovered through a customer charge. Implementation of this proposal would result in an immediate and drastic change in the rate structures currently used by Kentucky Power. Thus the Commission will not accept the Residential Intervenors proposal for rate design based on marginal cost at this time.

The Commission is concerned about the lack of documentation presented with the marginal cost study. Seventy-two pages of workpapers were provided; however they were most difficult to follow without proper footnotes and additional reference to the source of data. In the future, the Commission expects much more detailed documentation of the marginal cost study. Further, the Commission does not require that a marginal cost study be filed in the next rate case except to the extent it may be necessary for the development of cogeneration and small power production rates which may have to be filed.

Revenue Allocation

Kentucky Power witness, Mr. Robert Bibb, Rates and Tariffs Manager for Kentucky Power, presented class allocations of revenue increases based on the results of Kentucky Power's cost of service studies. The results of the time-differentiated study formed the

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69 Brief of Residential Intervenors, page 16.

primary basis for the proposed revenue allocation. Mr. Bibb proposed to allocate the revenue increase so as to move toward an equalization of the rates of return among classes. Since to move directly to equal rates of return among classes would result in an overwhelming increase to the residential class, Mr. Bibb proposed to limit the increase to the residential class to a 29 percent increase. The remainder of the proposed increase in revenue was allocated to the other classes of customers in a fashion that equalizes the proposed rates of return for each class. The resulting revenue increases and rates of return proposed for each class of customers is provided in Mr. Bibb's testimony.[70] In Mr. Bibb's supplemental testimony, he supported the proposition that any increase or reduction to the overall revenue increase of the company should be allocated among the customer classes in the same proportion as his proposed class allocations.[71]

The intervenors did not provide any witnesses concerning the proposed class allocations of revenue increases. As a consequence, no alternative class revenue allocations were proposed in this case.

During the cross-examination of Mr. Bibb, his procedure for determining class revenue increases was questioned. In particular, he was questioned about the increase proposed for the OP tariff.[72] Mr. Bibb compared the class index, which is a class

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70 Bibb Prefiled Testimony, page 13.

71 Bibb Supplemental Testimony, page 2.

72 T.E., Volume III of IV, October 11, 1984, pages 149-150.

rate of return divided by the overall company rate of return, for each of the tariff classes, using the present rates of return and the proposed rates of return. Mr. Bibb agreed that if the objective is to move all class rates of return closer to the company rate of return, then the class index should always move closer to the value 1 when the index for the present rates is compared to the index for the proposed rates.[73] For instance, the index for residential service ("RS") moves from .8, which is the RS rate of return given present rates (6.7%) divided by the overall company rate of return (8.38%), to .86 assuming the proposed rates were allowed. Similarly, the index for the general service ("GS") tariff decreases from 1.25 under present rates to 1.10 under the proposed rates. The movement of the index for each of the tariffs is in the appropriate direction except for the QP tariff. The index for the QP tariff goes from 1.08 to 1.10. Mr. Bibb acknowledged that the index for the QP tariff moved in the wrong direction to meet his objective of moving toward equalized class rates of return.[74] However, he also expressed his concern that any alternative allocation of revenue would very likely result in raising the revenue increase for the other classes, including the residential class.

The Commission is concerned that a strict formula approach as used by Kentucky Power in developing the allocation of the

[73] Ibid., pages 148-149.

[74] Ibid., page 150.

revenue increase to the classes of customers can possibly result in an undesirable shift in the revenue allocation. Kentucky Power seems very sensitive to the rate increases proposed for the residential class but considerably less sensitive to the increases for the other classes. This concern for the residential class is commendable; however, similar concern should be given to the other classes.

In this case only Kentucky Power has proposed an allocation of the revenue increase among the various customer classes. In fact, there are an infinite number of alternative revenue allocations that could be developed; however, any other allocation will benefit one class at the expense of another class. A reallocation of the revenue increase at this juncture in the proceeding seems inappropriate. Therefore, the Commission finds that the revenue increase granted in this case should be allocated in the same proportions as those proposed by Kentucky Power.

Time-of-Day Rates

Presently, Kentucky Power is in the midst of a rate design experiment to evaluate the cost effectiveness of time-of-day rates for certain large industrial customers. Kentucky Power has proposed in this case to pass through to the time-of-day customers the rate increases approved for the other industrial customers which are served under the OP tariff. Kentucky Power has also proposed to modify the design of the time-of-day tariff based on their revised TOD class cost of service study which placed some additional emphasis on the on-peak demand when compared to the TOD class cost of service study filed in the previous case. Through its cross-examination of Kentucky Power's witnesses, KIUC objected to the revised TOD study and the increased on-peak demand charge.

As stated above in the class cost of service studies section of this Order, the Commission finds the TOD study to be reasonable for rate design. Further, the Commission finds that the increases approved for the QP tariff should be passed through to the customers served on the Commercial and Industrial Power Time-of-Day Tariff ("CIP-TOD") in accordance with the methodology as presented in response to Item No. 15 of the Commission's Order dated July 20, 1984. Also, the Commission finds the proposed change in the on-peak hours to be appropriate. Kentucky Power shall file the revised CIP-TOD tariff with the workpapers within 20 days from the issuance of this Order. This is the same procedure used previously and was discussed at the hearing.[75]

Load Management Time-of-Day Rates

In this case Kentucky Power has proposed to modify its current Residential Service Load Management Time-of-Day tariff ("RS-LM-TOD"). The modification includes a separate metering provision for company approved load management devices. This will enable the tariff to be applied more broadly and include off-peak add-on resistance heating and water heating.

Also in this case Kentucky Power has proposed a load management time-of-day provision to its General Service ("GS") tariff. This provision will enable Kentucky Power to encourage the use of load management devices by commercial customers.

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75 T.E., Volume III, October 11, 1984, page 54.

After careful review, the Commission has determined that the adoption of both of these proposed provisions is appropriate. The associated incremental cost of both of these proposed provisions is recovered through the service charges and the off-peak energy charges recover the off-peak energy costs. The Commission believes the promotion of these load management benefits is a desirable objective and is pleased to see Kentucky Power become more active in these efforts.

Price Elasticity

Kentucky Power witness, Mr. Louis Jahn, presented testimony concerning the price elasticity effect of a rate increase granted by the Commission. While statistical estimates of this effect were produced by Kentucky Power, this information has not been used to adjust the proposed billing determinants. During cross-examination of Mr. Matthews, it was established that Kentucky Power was not requesting an adjustment to reflect price elasticity:

> Q All right. Well, maybe I misunderstood. I had read the testimony [of Mr. Jahn], and I thought you were asking for that [price elasticity] adjustment. Now you seem to be saying it's just being presented to show the Commission that you, in fact, would not earn everything--you would not earn the return requested if, in fact, 100% of the rate increase was granted--
>
> MR. WILSON [Counsel for Kentucky Power]: Exactly. Exactly so.
>
> Q --and you, in fact, are not asking for that [price elasticity] adjustment.
>
> MR. WILSON: Exactly so.

Q All right. Thank you. I have no further questions. Is that--let me--is that your understanding, too, Mr. Matthews?

A Yes. I--it was decided not to adjust the billing determinants, but I think it was a point that the--we wanted to bring out in the case, and it was included for that reason.[76]

In recent Kentucky Power rate cases, as well as those of other public utilities in Kentucky, the Commission has enunciated a consistent policy concerning proposed price elasticity adjustments. Had Kentucky Power specifically requested such an adjustment, there is nothing in this case to cause the Commission to deviate from that policy. Accordingly, a price elasticity adjustment has not been incorporated in the rates set forth in this Order.

Hanging Rock-Jefferson AFUDC

As part of its application in this case, Kentucky Power requested approval of a modification in accounting practices regarding AFUDC and depreciation of the Hanging Rock-Jefferson line. The modification involved permission to continue accruing AFUDC on the line from its September 1984 in-service date until the effective date of rates in this case and permission to defer any depreciation expense until that same date. This request came about due to Kentucky Power's decision to implement this rate increase in conjunction with the commercialization of Rockport.

As support for the request, Mr. Boyle explained that, under the instructions of the FERC Uniform System of Accounts, which

[76] T.E., Volume I, October 9, 1984, pages 71-72.

require that AFUDC cease and depreciation commence at the commercial operation date of a project, Kentucky Power's earnings for the period from September through November 1984 would be reduced by approximately 40 percent.[77] In addition, without the requested accounting modification Kentucky Power would never recover the capital costs incurred during that 3-month period.

None of the intervenors objected to the request and no modifications were proposed by any of the parties. The Commission is of the opinion that, in view of Kentucky Power's financial condition, and inasmuch as the request applies to a specific construction project, the proposed accounting treatment is both reasonable and appropriate. The Commission recognizes this to be an isolated incident caused by the timing of the Hanging Rock-Jefferson and Rockport projects. Furthermore, the Commission finds the accounting entries proposed by Kentucky Power to be proper and consistent with generally accepted accounting principles. Therefore, Kentucky Power is hereby authorized to continue AFUDC accrual for the Hanging Rock-Jefferson line from its in-service date up to the effective date of the rates approved herein. Kentucky Power is also authorized to defer depreciation on the Hanging Rock-Jefferson project until the effective date of the rates approved herein.

SUMMARY

The Commission, having considered the evidence of record and being advised, is of the opinion and finds that:

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77 Boyle Prefiled Testimony, page 5.

1. The rates in Appendix A are the fair, just and reasonable rates for Kentucky Power and, along with the rates to be filed within 20 days in the CIP-TOD, RS-TOD and RS-LM-TOD tariff sheets, will produce gross annual revenue of approximately $226,002,875. The rates for the CIP-TOD tariff are to be calculated as discussed in the previous section of this Order entitled Time-of-Day Rates.

2. The rates of return granted herein are fair, just and reasonable and will provide for the financial obligations of Kentucky Power with a reasonable amount remaining for equity growth.

3. The rates proposed by Kentucky Power would produce revenue in excess of that found reasonable herein and should be denied upon application of KRS 278.030.

4. The accounting treatment proposed by Kentucky Power regarding continued AFUDC and depreciation deferral for the Hanging Rock-Jefferson transmission line until the date of this Order is appropriate and consistent with generally accepted accounting principles and should be approved.

IT IS THEREFORE ORDERED that the rates in Appendix A and the rates to be filed in the CIP-TOD tariff as decribed in the Time-of-Day Rates section of this Order, as well as the RS-TOD, RS-LM-TOD and GS-LM-TOD tariffs are approved for service rendered on and after December 5, 1984.

IT IS FURTHER ORDERED that the rates proposed by Kentucky Power be and they hereby are denied.

IT IS FURTHER ORDERED that within 20 days from the date of this Order Kentucky Power shall file with the Commission the RS-TOD, RS-LM-TOD, and GS-LM-TOD tariff sheets which are to be tied to the RS and GS rates established herein.

IT IS FURTHER ORDERED that within 20 days from the date of this Order Kentucky Power shall file with the Commission the CIP-TOD tariff sheets and the supporting workpapers for those tariffs as discussed in the section of this Order entitled Time-of-Day Rates.

IT IS FURTHER ORDERED that the proposed accounting treatment for continued AFUDC and depreciation deferral for the Hanging Rock-Jefferson transmission line until the date of this Order be and it hereby is approved.

IT IS FURTHER ORDERED that within 30 days from the date of this Order Kentucky Power shall file with the Commission its revised tariff sheets setting out the rates approved herein.

Done at Frankfort, Kentucky, this 4th day of December, 1984.

PUBLIC SERVICE COMMISSION

Richard D. Heman Jr.

Chairman

Vice Chairman

Commissioner

ATTEST:

Secretary

APPENDIX A

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 9061 DATED DECEMBER 4, 1984.

The following rates and charges are prescribed for the customers in the area served by Kentucky Power Company. All other rates and charges, with the exception of all time of day tariffs which are to be filed within 20 days of the date of this Order, not specifically mentioned herein shall remain the same as those in effect under authority of this Commission prior to the effective date of this Order.

TARIFF R. S.
(Residential Service)

RATE

Service Charge	$4.25 per month
Energy Charge	
First 500 kwh per month	5.305¢ per kwh
All Over 500 kwh per month	4.631¢ per kwh

SPECIAL TERMS AND CONDITIONS.

This tariff is subject to the Company's Terms and Conditions of Service.

TARIFF G. S.
(General Service)

AVAILABILITY OF SERVICE

Available for general service to customers with normal maximum electrical capacity requirements of not more than 100 KW.

The rates for service at 2.4 KV and above as listed below are available only where the customer furnishes and maintains the complete substation equipment including all transformers and/or other apparatus necessary to take the entire service at the primary voltage of the transmission or distribution line from which service is to be received. The rates set forth in this tariff are based upon the delivery and measurement of energy at the same voltage.

Existing customers not meeting the above criteria will be permitted to continue service under present conditions only for continuous service at the premises occupied on or prior to December 5, 1984.

RATE

For Capacity Requirements less than 5 KW.

Service Charge	\$9.85 per month
Energy Charge per KWH:	
First 500 KWH per month	6.545¢ per KWH
All Over 500 KWH per month	4.069¢ per KWH
Monthly Minimum Charge	\$9.85

For Capacity Requirements of 5 KW and Above.

	Delivery Voltage	
	Below 2.4 KV	2.4 KV and Above
Service Charge per month	\$10.80	\$16.20
Demand Charge per KW	\$ 1.00	\$ 1.00
Energy Charge per KWH:		
KWH equal to 200 times KW of monthly billing demand	5.376¢	4.873¢
KWH in excess of 200 times KW of monthly billing demand	4.496¢	4.271¢

Monthly Minimum Charge as determined below.

MONTHLY BILLING DEMAND

Billing demand shall be taken monthly to be the highest registration of a 15-minute integrating demand meter or indicator, or the highest registration of a thermal type demand meter. The minimum billing demand shall be 5 KW.

MINIMUM CHARGE

This tariff is subject to a minimum charge equal to the sum of the service charge plus the demand charge multiplied by 5 KW for the demand portion (5KW and above) of the rate.

Industrial and coal mining customers contracting for 3-phase service after October 1, 1959 shall contract for capacity sufficient to meet their normal maximum demands in KW, but not less than 10 KW. Monthly billing demand of these customers shall not be less than 60% of contract capacity and the minimum monthly charge shall be \$4.15 per KW of monthly billing demand, subject to adjustment as determined under the fuel adjustment clause, plus the service charge.

TERM OF CONTRACT

Contracts under this tariff will be required of customers with normal maximum demands of 100 KW or greater, except for 3-phase service to industrial and coal mining customers as provided elsewhere in this tariff. Contracts under this tariff will be made for an initial period of not less than 1 year and shall remain in effect thereafter until either party shall give at least 6 months' written notice to the other of the intention to terminate the contract. The Company will have the right to make contracts for periods of longer than 1 year and to require contracts for customers with normal maximum demands of less than 100 KW.

SPECIAL TERMS AND CONDITIONS

This tariff is subject to the Company's Terms and Conditions of Service.

This tariff is also available to customers having other sources of electrical energy supply but who desire to purchase service from the Company. Where such conditions exist the customer shall contract for the maximum demand in KW which the Company might be required to furnish, but not less than 5 KW. The Company shall not be obligated to supply demands in excess of that contracted for. If the customer's actual demand, as determined by demand meter or indicator, in any month exceeds the amount of his then-existing contract demand, the contract demand shall then be increased automatically to the maximum demand so created by the customer. Where service is supplied under the provisions of this paragraph, the billing demand each month shall be the contract demand instead of the billing demand defined under paragraph "Monthly Billing Demand" and the minimum charge shall be as follows:

Service Charge	\$10.80 per month
First 5 KW or fraction there of contract demand	\$20.50 per month
Each KW of contract demand in excess of 5 KW	\$4.15 per month per KW

This tariff is available for resale service to mining and industrial customers who furnish service to customer-owned camps or villages where living quarters are rented to employees and where the customer purchases power at a single point for both his power and camp requirements.

SPECIAL TARIFF PROVISION FOR RECREATIONAL LIGHTING SERVICE

Available for service to customers with demands of 5 KW or greater and who own and maintain outdoor lighting facilities and associated equipment utilized at baseball diamonds, football stadiums, parks and other similar recreational areas. This service is available only during the hours between sunset and sunrise. Daytime use of energy under this rate is strictly forbidden except for the sole purpose of testing and maintaining the lighting system. All Terms and Conditions of Service applicable to Tariff G.S. customers will also apply to recreational customers except for the Availability of Service.

RATE

Service Charge	$10.80 per month
Energy Charge	5.305¢ per KWH

TARIFF L. G. S.
(Large General Service)

AVAILABILITY OF SERVICE

Available for general service. Customers shall contract for a definite amount of electrical capacity in kilovolt-amperes, which shall be sufficient to meet normal maximum requirements but in no case shall the capacity contracted for be less than 100 KVA nor more than 1000 KVA. The Company may not be required to supply capacity in excess of that contracted for except by mutual agreement. Contracts will be made in multiples of 25 KVA.

The rates for service at 2.4 KV and above as listed below are available only where the customer furnishes and maintains the complete substation equipment including all transformers and/or other apparatus necessary to take the entire service at the primary voltage of the transmission or distribution line from which service is to be received. The rate set forth in this tariff is based upon the delivery and measurement of energy at the same voltage.

Existing customers not meeting the above criteria will be permitted to continue service under present conditions only for continuous service at the premises occupied on or prior to December 5, 1984.

RATE

	Delivery Voltage		
	Under 2.4 KV	2.4 KV-12.5 KV	34.5 KV-69 KV
Service Charge per month	$85.00	$127.50	$535.50
Demand Charge per KVA	$2.75	$2.75	$2.75
Energy Charge per KWH	4.189¢	3.530¢	3.005¢

MONTHLY BILLING DEMAND

Billing demand in KVA shall be taken each month as the highest 15-minute integrated peak in kilowatts as registered during the month by a 15-minute integrating demand meter or indicator, or at the Company's option as the highest registration of a thermal type demand meter or indicator, divided by the average monthly power factor established during the month corrected to the nearest KVA. Monthly billing demand established hereunder shall not be less than the customer's contract capacity except that where the customer purchases his entire requirements for electric light, heat and power under this tariff the monthly billing demand shall not be less than 60% of the contract capacity. In no event shall the monthly billing demand be less than 100 KVA.

MINIMUM CHARGE

This tariff is subject to a minimum monthly charge equal to the sum of the service charge plus $2.75 per KVA of monthly billing demand.

TERM OF CONTRACT

Contracts under this tariff will be made for an initial period of not less than 1 year and shall remain in effect thereafter until either party shall give at least 6 months' written notice to the other of the intention to terminate the contract. The Company reserves the right to require initial contracts for periods greater than 1 year.

SPECIAL TERMS AND CONDITIONS

This tariff is subject to the Company's Terms and Conditions of Service.

This tariff is available for resale service to mining and industrial customers who furnish service to customer-owned camps or villages where living quarters are rented to employees and where the customer purchases power at a single point for both his power and camp requirements.

This tariff is also available to customers having other sources of energy supply but who desire to purchase service from the Company. Where such conditions exist the monthly billing demand shall not be less than the customer's contract capacity.

TARIFF Q.P.
(Quantity Power)

AVAILABILITY OF SERVICE

Available for power service. Customers shall contract for a definite amount of electrical capacity in kilowatts which shall be sufficient to meet normal maximum requirements, but in no case shall the capacity contracted for be less than 1,000 KW. The Company may not be required to supply capacity in excess of that contracted for except by mutual agreement. Contracts will be made in multiples of 100 KW.

The customer shall own, operate and maintain equipment, including all transformers, and other apparatus necessary for receiving and purchasing electric energy at the voltage of the transmission or distribution line from which service is delivered.

The rate set forth in this tariff is based upon the delivery and measurement of energy at the same voltage.

RATE

	Delivery Voltage		
	2.4 KV-12.5 KV	34.5 KV-69 KV	Above 69 KV
Service Charge per month	$276.00	$662.00	$1,353.00
Demand Charge per KW	$ 8.57	$ 7.80	$ 7.22
Energy Charge per KWH	1.928¢	1.887¢	1.866¢

Reactive Demand Charge:
For each kilovar of lagging reactive demand in excess of 50% of the KW of monthly billing demand $.49 per KVAR

MONTHLY BILLING DEMAND

The billing demand in KW shall be taken each month as the highest single 15-minute integrated peak in KW as registered during the month by a demand meter or indicator, or, at the Company's option, as the highest registration of a thermal type demand meter or indicator. The billing demand shall in no event be less than 60% of the contract capacity of the customer, nor less than 1,000 KW.

The reactive demand in KVARS shall be taken each month as the highest single 15-minute integrated peak in KVARS as registered during the month by a demand meter or indicator or at the Company's option, as the highest registration of a thermal type demand meter or indicator.

MINIMUM CHARGE

This tariff is subject to a minimum monthly charge equal to the sum of the service charge and the demand charge multiplied by the monthly billing demand.

TERM OF CONTRACT

Contracts under this tariff will be made for an initial period of not less than 2 years and shall remain in effect thereafter until either party shall give at least 12 months' written notice to the other of the intention to terminate the contract. The Company reserves the right to require initial contracts for periods greater than 2 years.

SPECIAL TERMS AND CONDITIONS

This tariff is subject to the Company's Terms and Conditions of Service.

This tariff is available to customers having other sources of energy supply.

This tariff is available for resale service to mining and industrial customers who furnish service to customer-owned camps or villages where living quarters are rented to employees and where the customers purchases power at a single point for both his power and camp requirements.

TARIFF O. L.
(Outdoor Lighting)

AVAILABLITY OF SERVICE

Available for outdoor lighting to individual customers in locations where municipal street lighting is not applicable.

MONTHLY RATE

A. OVERHEAD LIGHTING SERVICE

1. High Pressure Sodium

100 watts (9,500 Lumens)	$5.10 per lamp
200 watts (22,000 Lumens)	$7.75 per lamp

2. Mercury Vapor*

175 watts (7,000 Lumens)	$4.97 per lamp
250 watts (11,000 Lumens)	$6.60 per lamp
400 watts (20,000 Lumens)	$8.35 per lamp

3. Incandescent*

189 watts (2,500 Lumens)	$5.00 per lamp

Company will provide lamp, photo-electric relay control equipment, luminaire and upsweep arm not over six feet in length, and will mount same on an existing pole carrying secondary circuits.

B. POST-TOP LIGHTING SERVICE

1. Mercury Vapor*

175 watts (7,000 Lumens) on 12-foot post	$5.75 per lamp

2. High Pressure Sodium
100 watts (9,500 Lumens) on
12-foot post $8.75 per lamp

Company will provide lamp, photo-electric relay control equipment, luminaire, post, and installation including underground wiring for a distance of thirty feet from the Company's existing secondary circuits.

C. FLOODLIGHING SERVICE

1. High Pressure Sodium

200 watts (22,000 Lumens)	$ 9.00 per lamp
400 watts (50,000 Lumens)	$12.50 per lamp

Company will provide lamp, photo-electric relay control equipment, luminaire, mounting bracket, and mount same on an existing pole carrying secondary circuits.

When new or additional facilities, other than those specified in Paragraph A, B, and C, are to be installed by the Company, the customer in addition to the monthly charges, shall pay in advance the installation cost (labor and material) of such additional facilities.

*These lamps are not available for new installations.

SPECIAL TERMS AND CONDITIONS

This tariff is subject to the Company's Terms and Conditions of Service.

The Company shall have the option of rendering monthly or bimonthly bills.

TARIFF M. W.
(Municipal Waterworks)

AVAILABILITY OF SERVICE

Available only to incorporated cities and towns and authorized water districts and to utility companies operating under the jurisdiction of Public Service Commission of Kentucky for the supply of electric energy to waterworks systems and sewage disposal systems served under this tariff on September 1, 1982, and only for continuous service at the premises occupied by the customer on that date. If service hereunder is discontinued, it shall not again be available.

Customer shall contract with the Company for a reservation in capacity in kilovolt-amperes sufficient to meet with the maximum load which the Company may be required to furnish.

RATE

Service Charge	$22.90 per month
Energy Charge:	
All KWH used per month	4.326¢ per KWH

MIMIMUM CHARGE

This tariff is subject to a minimum monthly charge equal to the sum of the service charge plus $2.60 per KVA as determined from customer's total connected load. The minimum monthly charge shall be subject to adjustments as determined under the Fuel Adjustment Clause.

SPECIAL TERMS AND CONDITIONS

This tariff is subject to the Company's Terms and Conditions of Service.

This tariff is not available to customers having other sources of energy supply.

TARIFF I. R. P.
(Interruptible Power)

AVAILABILITY OF SERVICE

Available to industrial customers whose plants are located adjacent to existing transmission lines of the Company when the Company has sufficient capacity in generating stations and other facilities to supply the customer's requirements. The Company reserves the right to specify the times at which deliveries hereunder shall commence.

The customer shall contract for a definite amount of electrical capacity which shall be sufficient to meet his normal maximum requirements and the Company shall not be required to supply capacity in excess of that contracted for except by mutual agreement. Contracts hereunder will be made for minimum capacities of 5,000 KW.

The rates set forth in this tariff are based upon the delivery and measurement of energy as the same voltage. Company shall determine and advise customer which of its lines will be utilized to deliver service hereunder and shall specify the voltage thereof.

The customer shall own, operate, and maintain equipment, including all transformers, switches and other apparatus necessary for receiving and purchasing electric energy at the voltage of the transmission or distribution line from which service is delivered.

RATE

	DELIVERY VOLTAGE	
	34.5 KV-69 KV	ABOVE 69 KV
Service Charge per month	$662.00	$1,353.00
Demand Charge per KW	$ 6.63	$ 6.14
Energy Charge per KWH	1.887¢	1.866¢

Reactive Demand Charge
For each KVAR of reactive demand in excess of 50% of the KW of monthly billing demand $.49 per KVAR

MONTHLY BILLING DEMAND

The billing demand in KW shall be taken each month as the highest 15-minute integrated peak in KW as registered during the month by a demand meter or indicator, or, at the Company's option, as the highest registration of a thermal type demand meter or indicator. The billing demand shall not be less than 60% of the contract capacity of the customer, nor less than 5,000 KW.

The reactive demand in KVARS shall be taken each month as the highest single 15-minute integrated peak in KVARS as registered during the month by a demand meter or indicator or at the Company's option, as the highest registration of a thermal type demand meter or indicator.

MINIMUM CHARGE

This tariff is subject to a minimum monthly charge equal to the sum of the service charge and the demand charge multiplied by the monthly billing demand.

TERM OF CONTRACT

Contracts under this tariff will be made for an initial period of not less than 2 years and shall remain in effect thereafter until either party shall give at least 1 year's written notice to the other of the intention to terminate contract. The Company reserves the right to require initial contracts for periods greater than 2 years.

CONDITIONS OF SERVICE

1. The interruptible load shall be separately served and metered and shall at no time be connected to facilities serving the customer's firm load.

2. All local facilities for interrupting service to the interruptible load will be owned by the customer.

3. The frequency and duration of interruption shall not be limited.

4. If the customer fails to curtail load as requested by the Company, the Company reserves the right to interrupt the customer's entire load.

5. No responsibility of any kind shall attach to the Company for or on account of any loss or damage caused by or resulting from any interruption or curtailment of this service.

SPECIAL TERMS AND CONDITIOSN

This tariff is subject to the Company's Terms and Conditions of Service.

TERMS AND CONDITIONS OF SERVICE

EMPLOYEES' DISCOUNT

Regular employees who have been in the Company's employ for 6 months or more may, at the discretion of the Company, receive a reduction in their residence electric bills for the premises occupied by the employee.